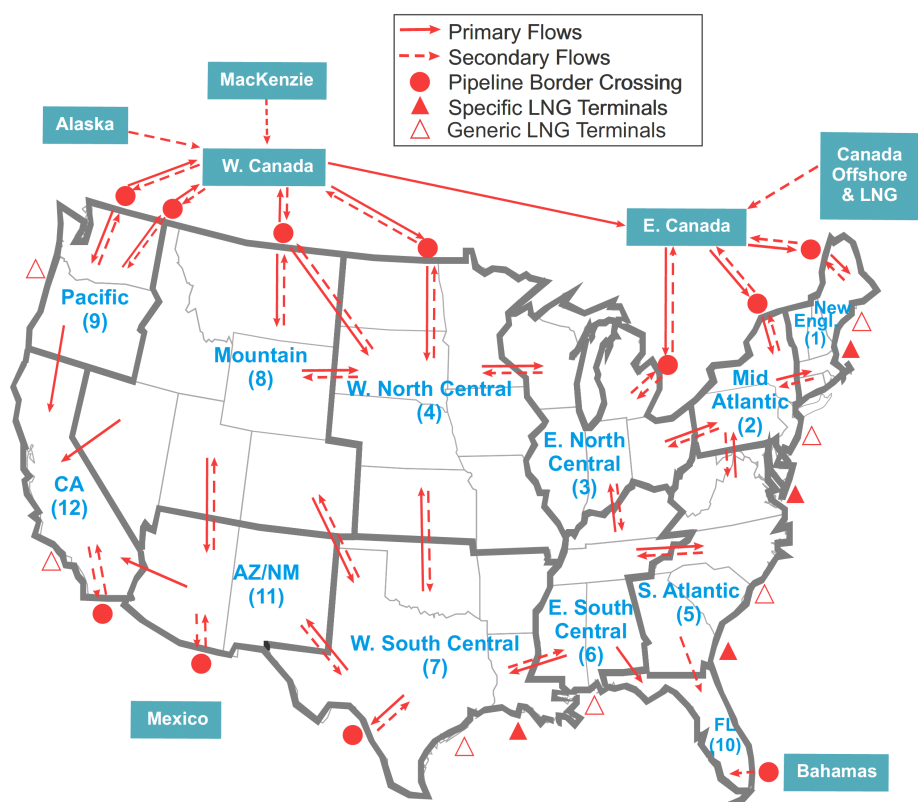


# Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through the regional interstate network, for both a peak (December through March) and off peak period during each projection year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. Natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of the supply options available to bring gas to market centers within each of the NGTDM regions (Figure 8). The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) structural components of the model, (2) capacity expansion and pricing of transmission and distribution services, (3) Arctic pipelines, and (4) imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in *Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System, Model Documentation 2008*, DOE/EIA-M062(2008) (Washington, DC, 2008).

**Figure 8. Natural Gas Transmission and Distribution Model Regions**



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

## Key Assumptions

### ***Structural Components***

The primary and secondary region-to-region flows represented in the model are shown in Figure 8. Primary flows are determined, along with nonassociated gas production levels, as the model equilibrates supply and demand. Associated-dissolved gas production is determined in the Oil and Gas Supply Module (OGSM). Secondary flows are established before the equilibration process and are generally set exogenously. Liquefied natural gas (LNG) imports are also not directly part of the equilibration process, but are set at the beginning of each NEMS iteration in response to the price from the previous iteration. Flows and production levels are determined for each season, linked by seasonal storage. When required, annual quantities (e.g., consumption levels) are split into peak and offpeak values based on historical averages. When multiple regions are contained in a Census Division, regional end-use consumption levels are approximated using historical average shares. Pipeline and storage capacity are added as warranted by the relative volumes and prices. Regional pipeline fuel and lease and plant fuel consumption are established by applying an historically based factor to the flow of gas through a region and the production in a region, respectively. Prices within the network, including at the borders and the wellhead, are largely determined during the equilibration process. Delivered prices for each sector are set by adding an endogenously estimated markup (generally a distributor tariff) to the regional representative citygate price. Supply curves and electric generator gas consumption are provided by other NEMS modules for subregions of the NGTDM regions, reflective of how their internal regions overlap with the NGTDM regions.

### ***Capacity Expansion and Pricing of Transmission and Distribution Services***

For the first 2 projection years, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and seasonal storage in the model. Subsequently, pipeline and storage capacity is added when increases in consumption, coupled with an anticipated price increase, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given an assumed increased tariff). Once it is determined that an expansion will occur, the associated capital costs are applied in the revenue requirement calculations in future years. Capital costs are assumed based on average costs of recent comparable expansions for compressors, looping, and new pipeline.

It is assumed that pipeline and local distribution companies build and subscribe to a portfolio of interstate pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 30 percent above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99 percent. In the off-peak period, the maximum is assumed to vary between 75 and 99 percent of the design capacity. The overall level and profile of consumption, as well as the availability and price of supplies, generally cause realized pipeline utilization levels to be lower than the maximum.

### ***Pricing of Services***

While transportation tariffs for interstate pipeline services are initially based on a regulated cost-of-service calculation, an adjustment to the tariffs is applied which is dependent on the realized utilization rate, to reflect a market-based differential. Transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base.

Delivered prices by sector and season are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional delivered and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor.

The distribution tariffs are projected using econometrically estimated equations, primarily in response to changes in consumption levels. An assumed differential is used to divide the industrial price into one for noncore customers (refineries and industrial boiler users) and one for core customers who have less alternative fuel options.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. In general, the distributor tariffs for natural gas to vehicles are set to EIA's *Natural Gas Annual* historical end-use prices minus citygate prices plus Federal and State VNG taxes (held constant in nominal dollars) plus an assumed dispensing cost. Dispensing costs are assumed to be \$3.93 and \$2.29 (2007 dollars per mcf) for non-fleet and fleet vehicles, respectively.

### ***Pipelines from Arctic Areas into Alberta***

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. Recent high natural gas prices seemingly raised the potential economic viability of such a project, although expected costs have increased as well. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 10.1. A calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect the potential impact on the market price once the pipeline comes on line.

To assess the market value of Alaskan and Mackenzie Valley gas against the lower-48 market, a price differential of \$0.70 (2007 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaska gas, relative to the lower 48 wellhead price, is approximately \$5.65 (2007 dollars per Mcf), with some variation across the projection due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is projected to commence if the assumed total costs for Alaska gas in the lower 48 States exceeds the average lower 48 gas price in each of the previous 2 years, on average over the previous 5 years (with greater weight applied to more recent years), and as expected to average over the next 3 years. An adjustment is made if prices were declining over the previous 5 years. Once the assumed 4-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by \$6.44 (2007 dollars per Mcf). Supplies to fill an expanded pipeline are assumed to require new gas wells. When the Alaska to Alberta pipeline is built in the model, additional pipeline capacity is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaska gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Natural gas production from the MacKenzie Delta is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaska-to-lower 48 pipeline, using the primary assumed parameters listed in Table 10.1. One exception is that wellhead costs are assumed to change across the projection period with estimated changes to drilling costs for the lower 48 States.

### ***Supplemental Natural Gas***

The projection for supplemental gas supply is identified for three separate categories: pipeline quality synthetic natural gas (SNG) from coal or coal-to-gas (CTG), SNG from liquids, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). The third category, other supplemental supplies, are held at a constant level of 10.3 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not believed to change significantly in the context of a reference case. SNG from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.7 billion cubic feet per year. SNG production from coal at the currently operating Great Plains Coal Gasification Plant is also assumed to continue through the projection period at an average historical level of 51.4 billion cubic feet per year. It is assumed that additional CTG facilities will be built if and when natural gas prices are high enough to make them economic. One CTG facility is assumed capable of processing 6,040 tons of

**Table 10.1. Primary Assumptions for Natural Gas Pipelines from Alaska and MacKenzie Delta into Alberta, Canada**

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	3.9 Bcf per day	1.1 Bcf per day
Expansion potential	22 percent	58 percent
Initial capitalization	27.6 billion (2007 dollars)	\$10.2 billion (2007 dollars)
Cost of Debt (premium over BAA bond rate)	0.0 percent	0.0 percent
Cost of equity (premium over 10 year treasury yield note)	7.5 percent	7.5 percent
Debt fraction	60 percent	60 percent
Depreciation period	20 years	20 years
Minimum wellhead price (including treatment and fuel costs)	\$1.65 (2007 dollars per Mcf)	\$3.02 (2007 dollars per Mcf)
Risk Premium	\$0.82 (2007 dollars per Mcf)	\$0.06 (2007 dollars per Mcf)
Additional cost for expansion	\$6.44 (2007 dollars per Mcf)	\$0.35 (2007 dollars per Mcf)
Construction period	4 years	4 years
Planning period	5 years	2 years
Earliest start year	2020	2014

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline cost data are based on November 2007 pipeline proposals submitted in compliance with the Alaska Gas line Inducement Act (A61A) requirements by Conoco Phillips and Trans Canada Pipelines to the State of Alaska.

National Energy Board of Canada, "Mackenzie Gas Project – Hearing Order GH-1-2004, Supplemental Information – Project Update 2007," dated May 15, 2007;

National Energy Board of Canada, "Mackenzie Gas Project – Project Cost Estimate and Schedule Update," dated March 12, 2007; Canada Revenue Agency, "T2 Corporation Income Tax Guide 2006," T4012(E) Rev. 07. Indian and Northern Affairs Canada, "Oil and Gas in Canada's North," website address [http://www.ainc-inac.gc.ca/ps/ecd/env/nor\\_e.html](http://www.ainc-inac.gc.ca/ps/ecd/env/nor_e.html).

National Energy Board of Canada, "Application for Approval of the Development Plan for Taglu Field - Project Description," submitted by Imperial Oil Resources Ltd., TDPA-P1, August 2004;

National Energy Board of Canada, "Application for Approval of the Development Plan for Niglintgak Field - Project Description," submitted by Shell Canada Ltd., NDPA-P1, August 2004; and

National Energy Board of Canada, "Application for Approval of the Development Plan for Parsons Lake Field - Project Description," submitted by ConocoPhillips Canada (North) Ltd., PLDPA-P1, August 2004.

bituminous coal per day, with a production capacity of 0.1 Bcf per day of synthetic fuel and approximately 100 megawatts of capacity for electricity cogeneration sold to the grid. A CTG facility of this size is assumed to cost over \$1.05 billion in initial capital investment (2007 dollars). CTG facilities are assumed to be built near existing coal mines. All NGTDM regions are considered potential locations for CTG facilities except for New England. Synthetic gas products from CTG facilities are assumed to be competitive when natural gas prices rise above the cost of CTG production (adjusted for credits from the sale of cogenerated electricity). It is assumed that CTG facilities will not be built before 2012.

## ***Natural Gas Imports and Exports***

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS starting at 534 billion cubic feet per year in 2008 and increasing to 739 tcf by 2030. Canadian production and U.S. import flows from Canada are determined endogenously within the model.

Growth rates for consumption in Mexico are set exogenously based on projections from the *International Energy Outlook 2008* and are provided in Table 10.2, along with initially assumed growth rates for production in Mexico from the same source. Adjustments are made endogenously within the model to reflect a response to price fluctuations within the market. Domestic production is assumed to be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico. The difference between production plus LNG imports and consumption in any year is assumed to be either imported from, or exported to, United States.

**Table 10.2. Assumed Annual Growth Rates for Mexico (percent)**

	Consumption	Production
2008 - 2010	1.0	0.1
2011- 2015	3.7	0.1
2016 - 2020	3.9	2.7
2021 - 2025	3.2	2.2
2026 - 2030	3.3	3.2

Source: EIA, International Energy Outlook 2008, DOE/EIA-0484(2008) and Energy Information Administration, Office of Integrated Analysis and Forecasting.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 10.3. Production in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an estimated production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells and a finding rate (both based on an econometric estimation). The initial coalbed methane, shale gas, and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 2004 are 70 trillion cubic feet, 30 trillion cubic feet (starting in 2010), and 92 trillion cubic feet, respectively.<sup>1</sup> Potential production from tight formations was approximated by increasing the conventional resource level by 1.5 percent annually. Production from coalbed and shale sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous projection year. To approximate the impact of the average increase in the Alberta royalty rate, starting in 2009 the price drivers (i.e., the price realized by producers) on western Canada supply in the model were assumed to be 5 percent less than they would have been otherwise.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to decrease from 2007 levels of 44 billion cubic feet per year through March of 2011, when the export license expires, and cease thereafter. LNG imports to the United States are determined endogenously within the model.

**Table 10.3. Exogenously Specified Canadian Production and Consumption**

(billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2005	3,400	151
2010	3,700	240
2015	4,000	530
2020	4,300	670
2025	4,600	820
2030	5,000	710

Source: Consumption - EIA, International Energy Outlook 2008, DOE/EIA-0484(2008); Production - Energy Information Administration, Office of Integrated Analysis and Forecasting.

For the most part, LNG imports are set endogenously in the model based on Atlantic/Pacific and peak/off-peak supply curves derived from model results generated by EIA's International Natural Gas Model (INGM). Prices from the previous model iteration are used to establish the total level of North American imports in the peak<sub>2</sub> or off-peak and in the Atlantic or Pacific. First assumed LNG imports which are consumed in Mexico<sub>2</sub> are subtracted (presuming the volumes are sufficient) and the remaining levels are allocated to the model regions based on last year's import levels, the available regasification capacity, and the relative prices. Regasification capacity is limited to facilities currently in existence and those already under construction and is fully sufficient to accommodate import levels projected by the model.

## Legislation and Regulations

The methodology for setting reservation fees for transportation services is initially based on a regulated rate calculation, but is ultimately consistent with FERC's alternative ratemaking and capacity release position in that it allows some flexibility in the rates pipelines ultimately charge. The methodology is market-based in that rates for transportation services will respond positively to increased demand for services while rates will decline (reflecting discounts to retain customers) should the demand for services decline.

A number of legislative actions have been taken to provide a more favorable environment for the introduction of new liquefied natural gas (LNG) regasification facilities in the United States. In December 2002 under the Hackberry Decision, FERC terminated open access requirements for new onshore LNG terminals, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The Maritime Security Act, signed into law in November 2002, also amended the Deepwater Port Act of 1974 to include offshore natural gas facilities, transferring jurisdiction for these facilities from the FERC to the Maritime Administration and the U.S. Coast Guard. The result should be to streamline the permitting process and relax regulator requirements. More recently an EPACT2005 provision clarified the role of the FERC as the final decision making body on issues concerning onshore LNG facilities. While none of these legislative/regulatory actions is explicitly represented in the modeling framework, these provisions are indirectly reflected in selected model parameters.

Section 116 of the Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2004 (H.R.4837) gives the Secretary of Energy the authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska, through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower 48 States. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. In aggregate the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) \$18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The assumed costs of borrowing money for the pipeline was reduced to reflect the decreased risk as a result of the loan guarantee.

Section 706 of the American Jobs Creation Act of 2004 (H.R.4520) provided a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the previously allowed 15-year recovery period, for tax purposes. The provision is effective for property placed in service after 2013 (or treated as such) and is assumed to have minimal impact on the decision to build the pipeline.

Section 707 of the American Jobs Creation Act extended the 15-percent tax credit previously applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision is effective for costs incurred after 2004. The impact of this tax credit is assumed to be factored into the cost estimates filed by the participating companies.

In 2005, Section 1113 of the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) raised the federal motor fuels tax for compressed natural gas vehicles (CNG) from 48.54 cents per Mcf to 18.3 cents per gasoline gallon equivalent (or about \$1.46 per Mcf), all in nominal dollars. The same section also allows for a motor fuels excise tax credit of \$0.50 per gasoline gallon equivalent to the seller through September 30, 2009. The tax rate assumed in the model was changed accordingly and assumed constant in nominal terms throughout the projection.

Section 312 of the Energy Policy Act of 2005 authorizes the Federal Energy Regulatory Commission (FERC) to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. Storage rates are allowed to vary in the model from regulation-based rates, depending on market conditions.

## **Natural Gas Transmission and Distribution Alternative Cases**

### ***High and Low Liquefied Natural Gas Import Cases***

Reference case assumptions regarding LNG imports to the U.S. reflect expectations of increasing global demand and non-competitive domestic natural gas prices relative to higher world LNG prices.

In the high LNG supply case, LNG imports to the U.S. are exogenously projected to increase over reference case levels to determine the potential impact of additional LNG imports on the U.S. natural gas market. LNG imports are set by multiplying the reference case import levels by a factor which starts at 1.0, increases linearly between 2010 and 2030, and results in an LNG import level 5 times the reference case level by 2030. LNG imports in the high LNG case reach a level that approaches the projected regasification capacity in the United States in the reference case.

In the low LNG supply case, LNG imports to the U.S. are projected to remain constant at 2009 LNG import levels from the reference case.

### ***No Alaska North Slope Natural Gas Pipeline Case***

The construction of a natural gas pipeline from the North Slope of Alaska (ANS) to the lower 48 states has been a matter of uncertainty for a number of years amidst increasing capital cost estimates and political and business concerns existing between the state government and North Slope producers. In prior AEO projections, the earliest start year for ANS pipeline transmission has generally been pushed back as these issues delay construction of the pipeline. In the AEO2009 reference case, it is projected that the ANS pipeline will begin transporting natural to the lower 48 states beginning in 2020, the earliest assumed start year.

In the No Alaska North Slope pipeline case, it is assumed that the ANS pipeline will not be built over the projection period. This results in slightly higher imports and increased domestic production.

## Notes and Sources

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[1] For unconventional (i.e., coalbed) -- Average undiscovered resources under the National Energy Board's Supply Push and Techno-vert scenarios in "Canada's Energy Future, Scenarios for Supply and Demand to 2025," 2003. For conventional -- "Canada's Conventional Natural Gas Resources -- A Status Report," April 2004. For shale gas a 5 percent recovery rate was assumed for a 600 trillion cubic feet estimate of gas-in-place, which is lower than some estimates.

[2] LNG imports into Mexico, for consumption in the country, at the two existing facilities (in Altamira and Baja) are assumed to maintain at about 90 Bcf per year throughout the forecast. An additional facility is assumed to come on-line in 2011 in southwest Mexico and phase up to an import level of 90 Bcf per year as well. These levels are based in part on Sener, "Prospectiva del Mercado de Gas Natural 2006-2015".